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Implications of hydropower variability from climate change for a future, highly-renewable electric grid in California

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HIGHLIGHTS

- Climate-induced variability in hydropower can increase greenhouse gas emissions.
- Higher dispatchable capacity needed to compensate for hydropower variability.
- Hydropower under climate change has minimal effects on renewable penetration.
- Higher hydropower variability increases natural gas power plant start up events.
- Climate-induced hydropower variability increases natural gas power plant downtime.

ABSTRACT

This study investigates how hydropower generation under climate change affects the ability of the electric grid to integrate high wind and solar capacities. Using California as an example, water reservoir releases are modeled as a function of hydrologic conditions in the context of a highly-renewable electric grid in the year 2050. The system is perturbed using different climate models under the Representative Concentration Pathway 8.5 climate scenario. The findings reveal that climate change impact on hydropower can increase greenhouse gas emissions up to 8.1% due to increased spillage of reservoir inflow reducing hydropower generation, but with minimal effects (< 1%) on renewable utilization and levelized cost of electricity. However, increases in dispatchable power plant capacity of +2.1 to +6.3% and decreases in the number of start-up events per power plant unit up to 3.1%, indicate that the majority of dispatchable natural gas power plant capacity is offline for most of the climate change scenarios. While system-wide performance metrics experience small impacts, climate change effects on hydropower generation increase both the need for dispatchable generation and the costs of electricity from these power plants to support large-scale wind and solar integration on the electric grid.

1. Introduction

The serious environmental and economic impacts of fossil fuel-based energy resources have motivated the development and deployment of renewable energy conversion technologies. California has developed aggressive policies to establish a renewable portfolio standard (RPS) that aims to meet 50% of retail electricity sales with renewable resources by 2030 [1] and provide 100% of retail electricity sales with carbon-free electricity by 2045 [2]. In addition, the state has established complementary policies such as reducing economy-wide greenhouse gas emissions to 80% below year 1990 levels by the year 2050 [3], which will require renewable capacities in excess of the 50% RPS target to be installed as noted by previous studies by E3 [4] and Wei et al. [5]. Finally, a governor executive order (B-55-18) targets economy-wide carbon neutrality by 2045 [6].

To support these goals, hydropower is considered one of the primary resources needed to balance the variability of wind and solar on the electric grid and can contribute to the overall reliability of California's future, highly renewable electric system [7]. Hydropower can supplement the integration of wind and solar power into electricity systems through the use of pumped hydropower energy storage for capturing excess renewable generation [8]. This is accomplished by optimizing facility dispatch schedules around renewable generation characteristics [9] and providing more flexible generation compared to conventional fossil-fuel based power plants [10]. Hydropower resources have several ideal characteristics for performing these functions, including but not limited to:

- Significantly lower life cycle greenhouse gas emissions compared to other dispatchable electricity technologies, such as natural gas-fired

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Nomenclature

AR4	Assessment Report 4
AR5	Assessment Report 5
CanESM2	Canadian Earth System Model 2
CNRM-CM5	Centre National de Recherches Meteorologiques – CMIP5
E3	Energy Environmental Economics
g	Gravitational acceleration
GHG	Greenhouse Gas Emissions
h	Hydraulic head of the hydropower facility
HadGEM2-ES	Hadley Global Environment Model 2 - Earth System
HiGRID	Holistic Grid Resource Integration and Deployment model
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized Cost of Electricity
LOCA	Localized Constructed Analogs
MCP	Market clearing price of electricity on the electric grid
MIROC5	Model for Interdisciplinary Research on Climate - version 5
NGCC	Natural Gas Combined Cycle
P_{cap}	Power capacity of a hydropower facility
$P_{gen}(t)$	Hourly electrical power output from a hydropower facility
$P_{NL}(t)$	Hourly net load demand on the electric grid
PV	Photovoltaic
Q_{day}	Daily water release volume determined from the water reservoir fill model
$Q_{out}(t)$	Hourly water volume released from a hydropower facility
RPS	Renewable Portfolio Standard
TWh	Terawatt-hour
UARP	Upper American River Project
η	Efficiency of the hydropower facility on a power basis

power plants [11].

- The ability to maintain high operating efficiencies at part load relative to natural gas-fired power plants.
- The capability to start-up, shut down, and ramp up or down in generation over short timescales.

Due to these characteristics, hydropower has been shown to be a valuable resource for balancing wind and solar variability [10]. Additionally, hydropower facilities can provide these characteristics at very low costs.

However, the availability of hydropower resources in California will be affected by climate change. Even with current climate conditions, hydroelectric generation in the state has varied in response to seasonal and annual precipitation levels. Historically, annual in-state hydroelectric generation is approximately 34 TWh, but has ranged from 59 TWh in 1983 to 14 TWh in 2015 during the last major drought [12]. This variability is presented visually in Fig. 1:

Under climate change, California has been projected to experience increased rainfall and lower snow yields, as well as earlier snowmelt as shown by Hayhoe et al. [13] and Madani et al. [14]. Since California has traditionally relied on the Sierra Nevada snowpack to provide steady runoff into reservoirs, this shift may lead to increased spill events and consequently, lost energy potential [15]. Climate change is also expected to increase the risk of droughts in California, which would lead to periods with lower than historical hydropower potential [16]. These factors increase the uncertainty surrounding future hydroelectric generation potential in the state.

Climate change has the potential to affect the dynamic capabilities of hydropower generation, which will be even more important in a future electricity system reliant on wind and solar generation. The projected hydrological impacts on surface water reservoirs can affect the ability of hydropower plants to counterbalance wind and solar variability. The reduction or absence of hydropower resources may result in the increased reliance on available conventional natural gas power plants to balance electric loads and generation, which occurred during the recent 2015 drought [17].

This study addresses how climate change can impact hydropower generation in isolation, and how these impacts can affect the ability of a future electric grid to support increased levels of wind and solar power integration. This study also aims to provide insight on the development of future electric grid resource plans that are more capable of supporting high wind and solar capacities while enduring the impacts of climate change.

Before proceeding, it is important to state the key limitations of this study. First, this study focuses on comparing a future 10-year period (2046–2055) to a historical period (2000–2009). Expanding the window of the future and current time periods or alternatively selecting different time periods for comparison may yield slightly different results. Second, this study draws upon a limited number of climate models and a single Representative Concentration Pathway (RCP).

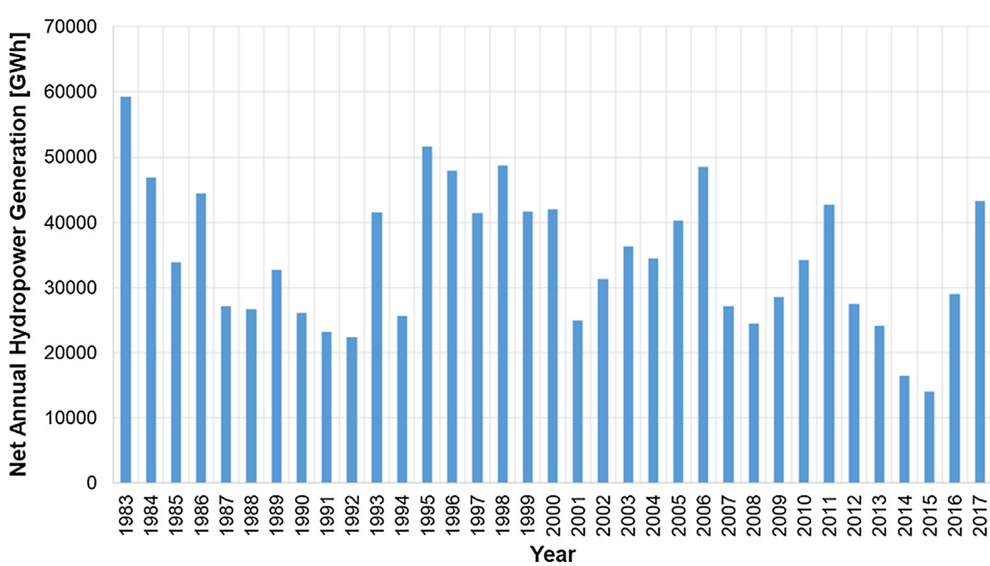

Fig. 1. Net annual hydropower generation in California, 1983–2017. Data from the California Energy Almanac [12].

Further analysis with other RCPs and an expanded set of climate models may also yield different results due to differences in human emissions scenarios and model parameterizations. Third, the composition of non-renewable, non-hydropower electricity resources in the future period is assumed to be natural gas-fired combined-cycle power plants. Assuming a different composition of dispatchable resources will affect the electric grid performance metrics presented here due to different dynamic capabilities and emissions intensities. Finally, a few simplifying assumptions have been made to render the scale of the interconnected systems tractable. These include the assumptions of fixed heads for hydropower reservoirs and constant hydropower efficiencies. Within the context of these limitations, this study provides some key insights into how climate change impacts on hydropower affect the ability of future electric grids to integrate wind and solar power.

The paper is organized as follows. Section 2 provides an overview of previous studies that have been conducted on climate change impacts on hydropower generation and concludes with a statement of the novelty and contribution of the current study. Section 3 presents the methodology that was used to conduct the current study. Section 4 presents the primary results of how climate change impacts electric grid operation and planning requirements in a future, highly renewable electric grid configuration which integrates large capacities of wind and solar generation. Section 5 presents the main conclusions of the study and provides discussion on the implication of the study results for future electric grid resource planning.

2. Background

2.1. California

The impacts of climate change on hydropower generation has been studied from a variety of perspectives. Vicuna et al. [15] examined how climate change impacts affect the Upper American River Project (UARP) and Big Creek hydropower systems in California. This study found that climate change reduces annual hydropower generation by up to 8.2% and 8% in the mid-21st century, and by 12.2% and 10.4% in the late 21st century for the UARP and Big Creek system respectively. The study identified changes and increased variability in runoff as driving factors of spillage [10]. Earlier work by Vicuna [18] for the same river system predicted a 10% reduction in hydropower generation for two of the climate change scenarios (GFDL-A2 and GFDL-B1) but approximately the same increase in generation for the other climate change scenarios (PCM-A2 and PCM-B1). Reinheimer et al. [19] examined how climate change impacts hydropower generation under the constraints of managing environmental flows in the Upper Yuba River hydropower system, finding that with 6 °C of warming, hydropower generation was reduced by up to 7.9%. Madani et al. [20] also examined climate impacts on high-elevation hydropower in California, concurrently evaluating hydropower supply and demand through electricity pricing. This study found decreases in hydropower generation of 19.8% for dry climate scenarios and increases of 5.8% for wet climate scenarios, but also found that increased spillage in the wet scenarios. Hydropower revenue, however, decreased in all except one wet climate scenario due to climate change. In summary, studies have been conducted to characterize how climate change affects hydropower from a bulk generation perspective in California.

2.2. United States of America

The impacts of climate change on hydropower have also been investigated in other regions of the United States. Hamlet et al. [21] examined the projected effects of climate change on energy supply and demand in the Pacific Northwest. In the Colombia River Basin, annual hydropower production was reduced by 2.0–3.4% by 2040, and 2.6–3.2% by 2080 with the largest reductions occurring in the summer during the times of peak air conditioning loads. Kao et al. [22] investigated climate change impacts on 132 federal hydropower facilities and 18 different regional areas in the United States. Using climate scenarios from the IPCC AR4 outputs, this study found that in the Pacific Northwest regions, average annual hydropower generation increased by 1.7% over 2010–2024 and by 3.3% over 2025–2039, but did not account for operational issues at the reservoir level. Robinson et al. [23] examined impacts of climate change on hydropower reservoirs in the Southeastern United States and found that with a 2 °C warming and a 10% decrease in precipitation, utilities will need a 10% increase in hydropower generation efficiency to offset reservoir drawdowns under climate change.

2.3. Other regions

Outside the United States, climate change impact studies have explored hydropower's role in the future electricity system. Zhou et al. [24] examined impacts of climate change on hydropower generation from an economic standpoint, focusing on changes in bulk hydropower generation in different countries. This study found that maximum achievable hydropower generation varied significantly between different regions, but changes in regional gross domestic product were relatively small. Teotonio et al. [25] examined climate change impacts on hydropower in Portugal by 2050. This study found that Portugal's hydropower generation may decrease by up to 41% by 2050 and cause a 17% increase in electricity prices. Fan et al. [26] examined the impact of climate change on hydropower generation in 28 provinces in China. This study found significant regional differences between northern and southern China, and generally found hydropower generation to increase on the country-wide scale. Koch et al. [27] examined climate change impacts on reservoirs and hydropower generation in the Upper Danube basin in central Europe, finding decreases in hydropower generation between 9.0% and 12.4% by 2036–2060 compared to the baseline period of 1971–2000. Bahadori [28] provided a review of future hydropower prospects in Australia. This review found that climate change is projected to increase evapotranspiration and reduce precipitation in southern and eastern Australia, which will create water security issues that can compromise hydropower generation. Gaudard et al. [29] provided a review perspective of hydropower under climate change in Europe. This review found that while hydropower generation can be negatively impacted by climate change, the energy potential of this resource remains significant and fulfills an important role in electricity supply security. Gaudard et al. [30] also examined the seasonality of hydropower generation in a run-of-the-river power plant in Italy. This study found that revenue for these facilities may be reduced by up to 20%, which can be exacerbated by changes in price seasonality.

2.4. Novelty and contribution of the current study

Much of the literature on climate change impacts on hydropower has been focused on reservoir operations, annual hydropower generation, and monthly or seasonal variability in reservoir inflow and generation. The literature lacks an understanding of how these impacts affect the electric grid and the implications for planning for the increased integration of renewable resources into the electric grid. On this topic, Tarroja et al. [31] conducted a study which translated climate change impacts using IPCC 5th Assessment Report climate scenarios to electric grid operational impacts of greenhouse gas emissions, cost of electricity, natural gas load following capacity, and natural gas fuel usage in California. This study was focused on a year 2030 electric grid configuration in California, which does not have the levels of wind and solar generation that are projected to be installed by the mid-21st century when greater climate change impacts are also expected to occur.

The current study extends the scope of the previous study by focusing on a year 2050 electric grid configuration, which has a significantly increased installation of wind and solar resources in the

realm of 80% to 90% renewable energy penetration. Previous studies such as Eichman [32] and NREL [33] show that grid dynamics change significantly as the renewable penetration level approaches very high levels, due to the variable nature of wind and solar generation. Therefore, the current study assesses the implications of climate change impacts on hydropower on a drastically different electric grid configuration that expresses the extreme level of temporal dynamics imposed by very high levels of wind and solar integration. This is also important to consider, since climate change impacts should be assessed on an electric grid configuration that will be in place by the time the corresponding climate change impacts will take effect.

Further, a study by Chang et al. [10] examined the importance of hydropower's role in mitigating variability from wind and solar generation. This study examined how the flexibility of hydropower resources could help mitigate undesirable grid dynamics imposed by wind and solar resources. This study concluded that hydropower can alter grid operations to allow larger capacities of wind and solar power to be readily integrated into the electric grid. While Chang et al. [10] focused on hydropower and renewable integration, this study did not account for the potential impacts of climate change.

In this context, the current study provides the following contribution to the literature regarding the impacts of climate change on hydropower and its implications:

- First, the current study provides an understanding of how climate change impacts on hydropower generation affect the ability of the electric grid to support high levels of wind and solar resource integration, which has not yet been established.
- Second, the current study provides insight into how the design and operation of electric grid resources must be altered to endure the aforementioned impacts and robustly support large-scale integration of wind and solar.

3. Approach and methods

3.1. Summary

A general overview of the approach used to carry out this study is presented in Fig. 2. Specific details on each of these steps will be provided in the following subsections. In summary, four different climate models were selected from the IPCC AR5 study, and downscaled hydrologic data was obtained from the Scripps Institute of Oceanography for these scenarios. Runoff, routed streamflow, reservoir operational parameters, and demand profiles were input into a model which simulated daily reservoir water releases for 60 water reservoirs in California. These daily reservoir water releases were used as constraints on the hourly dispatch of electricity generation from hydropower facilities attached to these reservoirs in response to electric grid conditions. Once the hourly dispatch was solved, the final hydropower profile was imposed on the electric grid in a year 2050 electric resource configuration using the Holistic Grid Resource Integration and Deployment (HiGRID) model [32,34]. This model provided the hourly operation of electric grid resources, capacity requirements, power plant behavior, greenhouse gas emissions, renewable resource penetration, and the levelized cost of electricity.

3.2. Climate scenarios and downscaled hydrologic data

We used four climate models for this study under the Representative Concentration Pathway 8.5 (RCP8.5) climate scenario from the IPCC AR5 documentation: CanESM2, CNRM-CM5, HadGEM2-ES, MIROC5, and an Extended Drought scenario which was derived from the HadGEM2-ES scenario and produced by the Scripps Institute of Oceanography. These models were chosen for use in the California 4th Climate Assessment [35]. The CanESM2 climate model represents a balance between warm/dry and cool/wet climate conditions in the ensemble of models used in the IPCC AR5 work. The CNRM-CM5 represents a cool/wet model bound, the HadGEM2-ES climate model represents warm/dry conditions, and the MIROC5 model represents a more variable model that spans different conditions. The extended drought scenario represents the occurrence of a 20-year drought in California and was produced specifically for the California 4th Climate Assessment [35]. Due to climate change, prolonged droughts may become more common in California. This scenario allows the current study to examine this effect.

We used runoff derived from the 1/16° VIC hydrological model simulations, forced with meteorological inputs from Localized Constructed Analogs (LOCA) downscaled climate model simulations

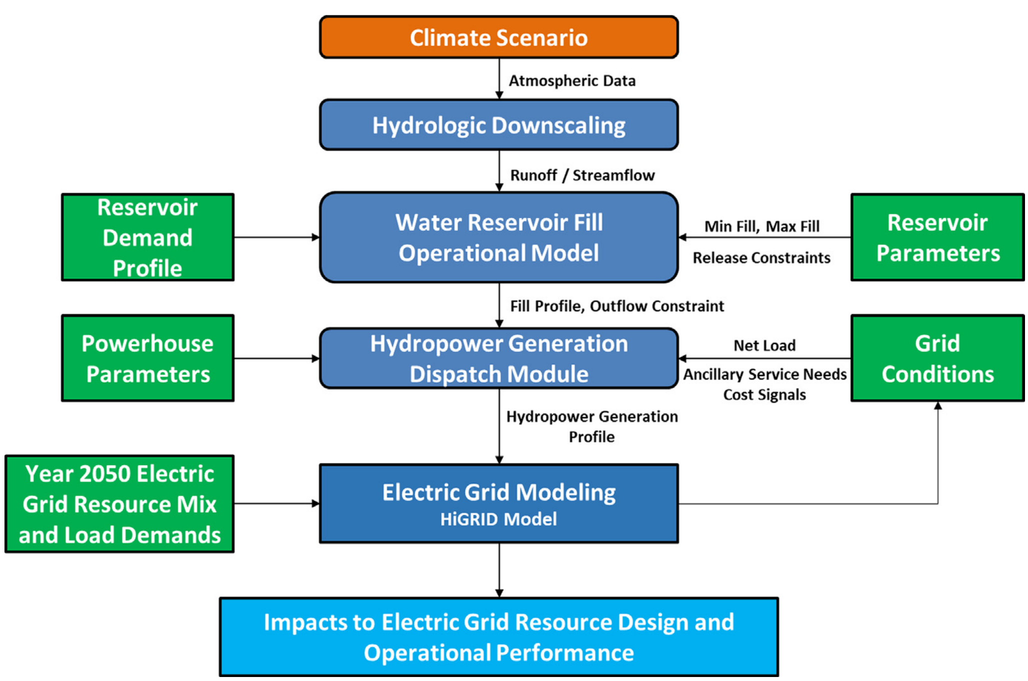

Fig. 2. Overview of the study approach.

[36,37]. The future period in this study was selected as 2046–2055, and we applied the difference in data values between future simulations and our baseline period of 2000–2009 as a modification to actual reservoir inflow data from the Department of Water Resources [38] and United States Geological Survey [39].

3.3. Water reservoir fill and release modeling

This study utilized a water reservoir network modeling approach based on the methodology described by Van Beek et al. [40], Haddeland et al. [41], and Hanasaki et al. [42] which was previously adopted and deployed by Tarroja to analyze water-energy resource interactions [43,44] and climate change impacts on hydropower and the electric grid in a low-renewable content configuration [31]. In summary, this modeling platform takes in temporally resolved inflow and demand profiles for individual reservoirs and uses rules for daily water releases based on calibration with 2000–2009 historical data. For more detail, the reader is referred to the aforementioned publications. Documentation of this methodology is also presented in a paper by Forrest et al. [45].

This water reservoir network model was applied to 60 hydropower facilities in California, an expansion from the 13 reservoirs analyzed by Tarroja et al. [31]. A map of the hydropower facilities considered in this study is presented in Fig. 3, and a list of the hydropower facilities and coordinates is presented in the Supplemental Information. Each reservoir has a minimum fill level below which no electric power or ancillary services can be generated, referred to as the dead pool reservoir level. For this study, the dead pool level was used as the minimum, which represents where the height of the water level falls below the intake structures for the hydropower plants. Below this level, water cannot be extracted from the reservoir using gravity and it is assumed that hydropower generation must cease in this condition.

It is important to note that we only considered reservoirs with "large hydropower" facilities, based on the classification used by the California Energy Commission (CEC) [12]. Large hydropower refers to facilities with a nameplate capacity of 30 MW or greater. In California, large hydropower facilities constitute 87.5% of total hydropower capacity in the state [12]. It is important to note there are facilities with large electricity production capacities but small water storage capacities; these were still included in the study. The reservoir release modeling produced the daily-resolved water release profile spanning the 10-year analysis period for historical climate conditions (2000–2009) and the future climate conditions (2046–2055) from each of the 60 water reservoirs and passed to the hydropower generation dispatch module.

3.4. Hydropower generation dispatch and electric grid modeling

For each day, we determined the hourly profile of electricity generation from each hydropower facility in response to cost signals from the electric grid. We constrained the electric grid with the daily water release determined by the water reservoir fill module and hydropower capacity. We generated the hourly electricity generation profile by employing an optimization which seeks to maximize revenue for each hydropower facility for providing electricity generation during each day:

$$min\left(-\sum \left(P_{gen}(t)\cdot MCP(P_{NL}(t))\right)\right) \tag{1}$$

Such that:

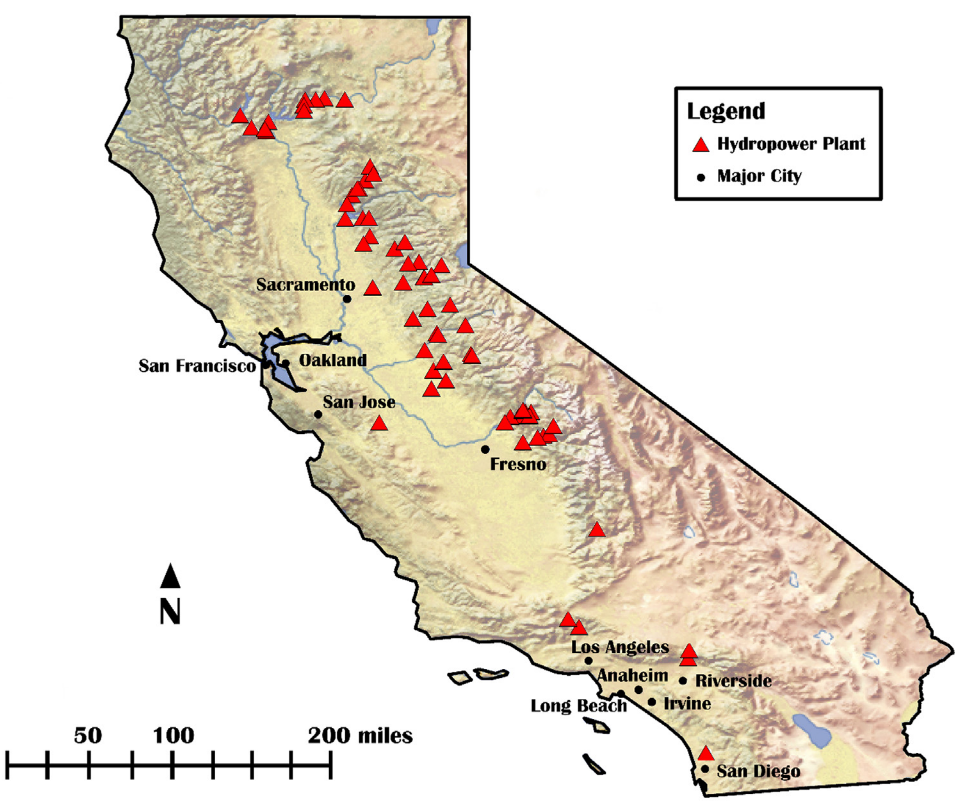

Fig. 3. Location of 60 hydroelectric power plants considered in this study (The California map used in this article was created using ArcGIS® software by Esri. ArcGIS® and ArcMap™ is the intellectual property of Esri and is used herein under license. Copyright © Esri. All rights reserved.)

$$P_{gen}(t) < P_{cap} \quad (2)$$

$$sum(Q_{out}(t)) = Q_{day} \quad (3)$$

$$Q_{out}(t) = \frac{P_{gen}(t)}{\eta \rho g h} \quad (4)$$

where

$P_{gen}(t)$ = Hourly electrical power output from the hydropower facility [MW]
MCP = Market clearing price of electricity on the electric grid [$/MWh]
$P_{NL}(t)$ = The net load demand on the electric grid [MW].
P_{cap} = The power capacity of the hydropower facility
$Q_{out}(t)$ = The hourly water volume released from the hydropower facility [m^3]
Q_{day} = The daily water release volume determined from the water reservoir fill model [m^3]
h = The hydraulic head of the hydropower facility [m]
g = Gravitational acceleration [m/s^2]
η = Efficiency of the hydropower facility on a power basis [fraction]

In summary, these equations dictate that each hydropower facility will dispatch its hourly profile to maximize revenue by providing electricity generation when it is most valuable, subject to the constraints that generation cannot exceed nameplate capacity and the amount of water released must be equal to the water reservoir operational requirements. In this study, we assume that the market clearing price of electricity is proportional to the net load demand on the electric grid. The net load demand is the total load demand minus must-take renewable generation, which we defined as wind and solar generation in this study. The resulting generation profiles for each of the 60 hydropower facilities were added together to determine the systemwide hydropower generation profile. The optimization of the hydropower generation profile from each reservoir in each day is carried out using the interior-point algorithm using the "fmincon" function implemented in MATLAB. The interior-point algorithm provides solutions for the nonlinear constrained optimization problems. While the optimization problem solved in this study (Eqs. (1)–(4)) is not necessarily a nonlinear optimization problem, the hydropower reservoir modeling framework is developed to allow the use of nonlinear constraints in addressing other research questions.

We obtained data on the net load demand and therefore the market clearing price from the Holistic Grid Resource Integration and Deployment (HiGRID) model. The HiGRID model is an hourly resolved electric grid resource dispatch model which determines the response of electric grid resources to changes in technology configuration, perturbations in load demand, and environmental forcing factors. HiGRID was originally developed with funding from the CEC to investigate the response of the electric grid to the large-scale integration of renewable resources. HiGRID has since been expanded to investigate transportation-electricity interactions [46–48], water-energy interactions [43,44], and precursor work on translating climate change impacts on hydropower to the electric grid on a low-renewable electric grid [31]. The HiGRID model includes hourly-resolved simulations of wind and solar power generation based on data from the NREL Western Wind and Solar Integration (WWSI) project as well as direct and diffuse insolation inputs obtained from the National Solar Radiation Database (NSDRB). For more detail on the renewable modeling, the reader is referred to Samuelsen et al. [49]. The hydropower generation model was validated for 2000–2009 against historical data for electricity generation from the power plants considered in this study. The aggregate error of this modeling approach for each year is presented in Table 1:

The existing errors are due to a number of different factors. First, the reservoir model is based on general rules governing the release of water from reservoirs given knowledge of inflow, reservoir level, capacity and flow constraints, and demand. However, this model cannot account for water reservoir operation events that are based on manual decisions by the reservoir operators, or that are outside of normal operating practices for a given reservoir. These events, while relatively rare in the historical record, do cause errors in our modeling.

The imposition of the hydropower dispatch onto the electric grid was done iteratively. We simulated a year 2050 electric grid resource configuration in HiGRID to produce the net load demand profile for the period of 2046–2055 and subsequently the market clearing price for electricity at each hour without the effects of hydropower. Renewable resources such as wind and solar are generally considered to be 'must-take' to the extent possible, this means that wind and solar resources do not have to bid into the electricity markets and compete with other resources to meet available demand. However, this does not prevent wind and solar generation from being curtailed when total generation exceeds electricity demand. The cost signal for electricity pricing was passed to the hydropower dispatch module, where hydropower facilities dispatch their hourly generation to maximize their revenue. In doing so, hydropower resources reduced the net load demand by providing bulk generation and also acted to smooth the variability of the net load profile. The updated net load profile, which accounts for hydropower dispatch, represents the remaining load profile that must be met by non-renewable resources. We passed this profile back to the HiGRID model and the final dispatch of electric grid resources was determined.

The year 2050 electric grid configuration for California is based on the PATHWAYS study by Energy Environmental Economics (E3) [4]. The 2015 E3 PATHWAYS study analyzed different pathways by which California's economic sectors (including energy) can evolve over time to achieve its 2050 goal of 80% reduction in greenhouse gas emissions from 1990 levels. This study used parameters from the E3 study for the renewable resource mix, complementary resources installed, and electric loads (Tables 2 and 3).

As outputs from the HiGRID model, the following metrics which characterize the performance and operational characteristics of electric grid resources are produced:

- **Greenhouse Gas (GHG) Emissions:** This refers to the greenhouse gas emissions produced by relevant electric grid resources.
  - o Significance: Reducing greenhouse gas emissions is a key environmental metric associated with climate change mitigation.
- **Renewable Penetration:** This refers to the percentage of the electric load demand that is satisfied by renewable energy resources, accounting for any curtailment of electric power generation.
  - o Significance: Increasing renewable penetration is a desirable outcome for reducing electric grid reliance on finite resources.
- **Levelized Cost of Electricity (LCOE):** This refers to the grid-wide average cost of electricity based on the installed resources and their operation.
  - o Significance: This refers to the costs that owners of electric grid resources (and subsequently ratepayers consuming electricity) will be burdened to economically sustain the installation and

Table 1
Historical aggregate error for hydropower generation calculations.

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Aggregate error	−0.1%	5.6%	1.5%	0.8%	0.7%	1.8%	−1.1%	2.1%	3.7%	2.2%

Table 2
Annual electric load demand magnitudes.

Sector	Annual electric load magnitude [GWh]
Residential	114,571
Commercial	134,856
Industrial/other	71,927
Transportation – light duty electric vehicles	49,154
Transportation – other electric	42,139
Transportation – hydrogen production	43,458

Table 3
Year 2050 renewable capacity levels.

Grid resource	Installed capacity [GW]
Centralized solar PV	83.92
Rooftop solar PV	29.00
Centralized wind	64.09
Geothermal	4.46
Hydropower	15.62
Energy storage	29.75

operation of these resources. A lower LCOE is desirable.

- **Natural Gas Combined Cycle (NGCC) Capacity Requirement:** This refers to the capacity of natural gas-combined cycle load-following power plants that must be installed to satisfy the electric load demand.
  - o Significance: To ensure that the load demand is satisfied, sufficient generation capacity must be installed to meet peak of the load demand profile and meet ancillary service requirements over the entire 10-year period. A lower capacity requirement is desirable, since fewer resources would be required to reliably operate the electric grid.
- **Peaker Capacity Requirement:** This refers to the capacity of fast-response, simple gas-turbine cycle peaking power plants that must be installed to satisfy the electric load demand.
  - o Significance: This metric is similar to the capacity requirement for natural gas combined cycles but applied to fast-response peaking power plants only. If peak load demands on the electric grid occur after fast-ramping events, fast-response power plants may be required to satisfy the load. A lower capacity requirement is desirable.
- **Power Plant Start-Up Events:** This refers to the number and type of start-up events that natural gas combined cycle and simple cycle peaking power plants must endure to satisfy the load demand. There are two metrics in this category: total start-up events and start-up events per power plant unit.
  - o Significance: **Total start-up events** are associated with increased criteria pollutant emissions. Upon start-up, fuel must be burned to heat power plant components up to operating temperature. Emissions cleanup equipment such as selective catalytic reduction, however, must reach a certain temperature range before being effective at cleaning up criteria pollutant emissions from combustion. Therefore, during a start-up event, power plants exhibit significantly increased criteria pollutant emissions. A lower number of events is desirable.
  - o Significance: **Start-up events per power plant unit** for thermal power plants are associated with degradation and reduction in the lifetime of power plant units due to thermal fatigue. A lower number of events is also desirable.

The results for this study are presented as a percentage change from the base case (year 2050 with hydropower without climate change) in each of the future cases representing climate change impacts on hydropower.

4. Results

4.1. Impacts on GHG emissions, renewable penetration, and Levelized Cost of Electricity (LCOE)

Fig. 4 presents the change in electric grid greenhouse gas emissions due to climate change impacts on hydropower generation. Each box plot is associated with a different climate scenario, with the black dot representing the average values over the 10-year period, the lower and upper bounds of the boxes representing the 25th and 75th percentiles, respectively, and the black lines indicating the maximum and minimum values. The red crosses represent values outside of the distribution assumed by the box. Fig. 5 presents the net generation and potential generation for the base case (historical climate) and the five climate scenarios.

Under the CanESM2 and CNRM-CM5 models, significantly higher water volumes were passed through the hydropower turbines due to

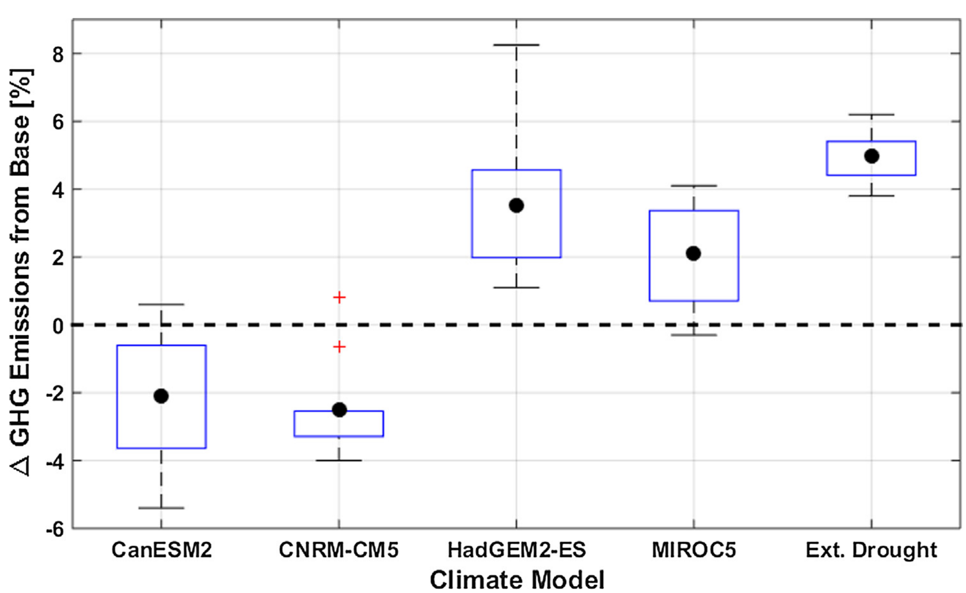

Fig. 4. Change in greenhouse gas emissions from the base case under different climate models. Base case value is 18.04 MMT CO_2e/yr.

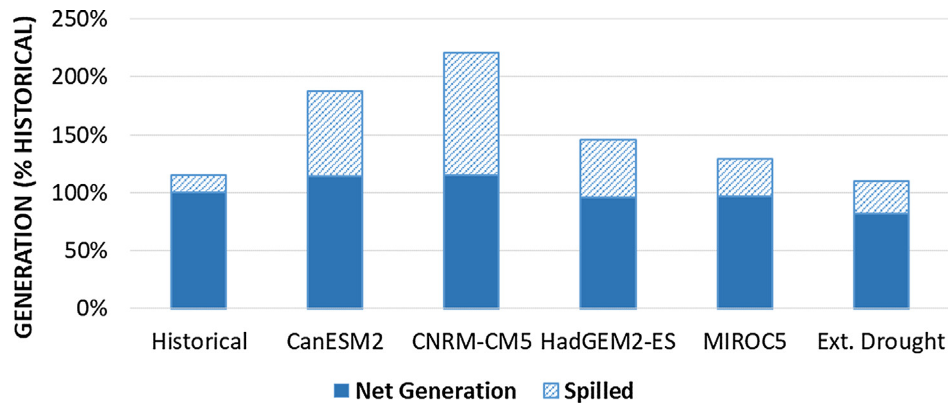

Fig. 5. Hydropower generation as a percentage of the base case. Net generation refers to hydropower electricity production from water which passes through the turbines. Spilled indicates lost generation potential due to reservoir overflow, causing water volume to bypass the hydropower turbines.

projected increases in precipitation and inflow volume. While precipitation variability increased, the overall volume of water introduced to the reservoirs was large enough to increase hydropower generation but only slightly due to increased spillage. For CanESM2 and CNRM-CM5, the mean change in electric grid greenhouse gas emissions was −2.1% and −2.5% from the base case.

The HadGEM2-ES and MIROC5 models exhibited increases in greenhouse gas emissions. In these scenarios, the total water volume introduced to the reservoirs was still larger than the base case, but not enough to overcome the increased water spillage caused by inflow variability. The net result was a decrease in hydropower generation which was compensated for by natural gas power plants, causing an average increase of 3.7% and 2.2% in annual greenhouse gas emissions for the HadGEM2-ES and MIROC5 models, respectively. In particular, the greenhouse gas emissions in the case using the HadGEM2-ES model spanned a large range between maximum and minimum values. Annual greenhouse gas emissions increased up to 8.1% during one year of the 10-year period, but only increased 0.9% during another year. This highlights the inter-annual precipitation variability with this model – with long dry periods causing significant greenhouse gas emissions increases and the opposite occurring during wet periods.

The Extended Drought case showed the highest average increase in greenhouse gas emissions of 4.9% above the base case. In this scenario, the low water volume introduced to reservoirs caused a decrease in hydropower generation and a large increase in greenhouse gas emissions. This case, however, did not exhibit the wet years that the HadGEM2-ES and MIROC5 models presented and was consistently drier from year to year.

The results for the change in electric grid renewable penetration due to climate change impacts on hydropower generation is presented in Fig. 6. This figure is interpreted similarly to Fig. 4, with the exception that the unit on the y-axis is percentage points.

The scenarios (CanESM2, CNRM-CM5) which exhibited decreases in greenhouse gas emissions (desirable outcome) also exhibited decreases in the electric grid renewable penetration (undesirable outcome), but the overall amount of change regarding the latter are relatively small (less than 1 percentage point). These results occurred due to the presence of excess renewable generation on the electric grid in the base case. When hydropower generation decreased in the drier models, excess wind and solar generation was harnessed instead of natural gas power plants. Conversely, increased hydropower generation in the wetter models occasionally occurred during times of high wind and solar generation, which causes curtailment of electricity generation from those resources. However, this result is due to California's definition of large hydropower plants as non-renewable, due to concerns about impacts on river ecosystems.

The renewable penetration of the base case is 71.9% and in all climate change scenarios, this metric changed by less than 1 percentage point. From these results, the projected climate scenarios do not compromise California's ability to reach its renewable portfolio standard

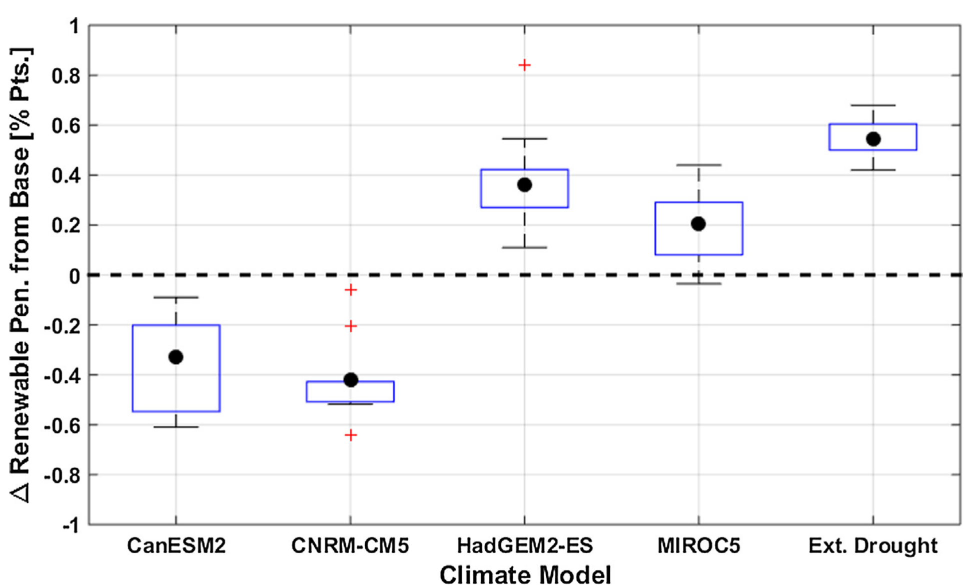

Fig. 6. Change in electric grid renewable penetration from the base case under different climate models.

goals.

The results for the change in the levelized cost of electricity (LCOE) due to climate change impacts on hydropower generation is presented in Fig. 7.

Climate change impacts on hydropower LCOE were also relatively small, with all cases only perturbing the LCOE by a range of −0.43 to +0.82%. This occurred as small changes in hydropower behavior do not result in significant system-wide LCOE changes with such high renewable capacities and flexible resources on the electric grid and the supporting (as opposed to major) role of hydropower in the electric grid resource mix. In our scenarios, system-wide LCOE was mainly governed by the behavior of renewable generation and complementary resources such as energy storage. However, this does not mean that costs for particular stakeholders (i.e. power plant owners) did not experience significant impacts.

The drier models (HadGEM2-ES, MIROC5, and Extended Drought) exhibited small increases in the system-wide LCOE. As explained in the results for renewable penetration, increased use of otherwise curtailed renewable generation improves the economics of wind and solar resources which are very sensitive to changes in capacity factor. While hydropower (a low-cost resource) is being displaced in these cases, the replacement electricity generation is even more low cost or free as the resource would have been wasted otherwise. This also explains the lower average increase in LCOE of +0.39% in the Extended Drought in comparison to the HadGEM2-ES case, which exhibited a +0.44% increase from the base case, since the larger shortfall in hydropower generation allowed higher uptake of otherwise curtailed renewable generation.

4.2. Impacts on power plant capacity and operations

The results of the previous subsection characterized the impacts of hydropower under climate change in terms of system-wide performance metrics. This subsection will focus on the more specific impacts to the operation and sizing of the dispatchable power plant fleet on the electric grid.

The results for the change in NGCC capacity requirements due to climate change impacts on hydropower generation is presented in Fig. 8.

For these results, the maximum value for each case is more significant than the average value. NGCC power plants are tasked with ensuring that the electric load demand is balanced and compensates for differences between the generation profile of other electric grid resources and the load demand profile. Therefore, even if only one hour out of the 10-year period exhibits a high load demand after other resources have already been dispatched, the NGCC power plant capacity must be installed in the system to sufficiently satisfy it.

Focusing on the maximum value, climate change increased NGCC capacity requirements on the electric grid by +2.1%, +1.4%, +6.2%, +6.3%, and +5.4% for the CanESM2, CNRM-CM5, HadGEM2-ES, MIROC5, and Extended Drought cases respectively. The wetter CanESM2 and CNRM-CM5 models required smaller increases due to the higher availability of hydropower generation in meeting peak demands, whereas the drier models required larger increases to compensate for shortfalls in hydropower generation. The increased year-to-year variability in the HadGEM2-ES, MIROC5, and Extended Drought models, as shown by the larger range in annual NGCC capacity requirement values, indicates that the NGCC power plant fleet will be underutilized for most of their lifetime. This can result in increased costs for NGCC power plant owners.

The potentially higher costs for NGCC power plant owners is not reflected in the systemwide LCOE results presented earlier. This indicates that while system-wide cost increases are minimal, this does not necessarily mean that individual stakeholders will not bear significant impacts. These results imply that the owners of NGCC power plants may disproportionately bear the cost impacts associated with climate change impacts on the electricity system through hydropower. In cases even where systemwide costs even decrease slightly, NGCC power plants owners as an individual stakeholder may still experience cost increases.

The results for the change in total NGCC start-up events due to climate change impacts on hydropower generation is presented in Fig. 9:

Start-up events were categorized into four types based on the time period that a power plant was inactive before having to start-up. Based on information for combined cycle power plants provided by NREL [50], a downtime of less than 5 h is considered a "hot" start, between 5 and 40 h of downtime is considered a "warm" start, and more than 40 h is considered a "cold" start. Longer times between start-up events are undesirable. If a power plant is inactive for a long period of time, the plant's component temperatures drop to lower levels. Upon start-up, these components must be increased to the specified operating temperature for the power plant to operate. Longer downtimes between starts therefore represent a larger temperature range across which power plant components must be heated and longer periods of time

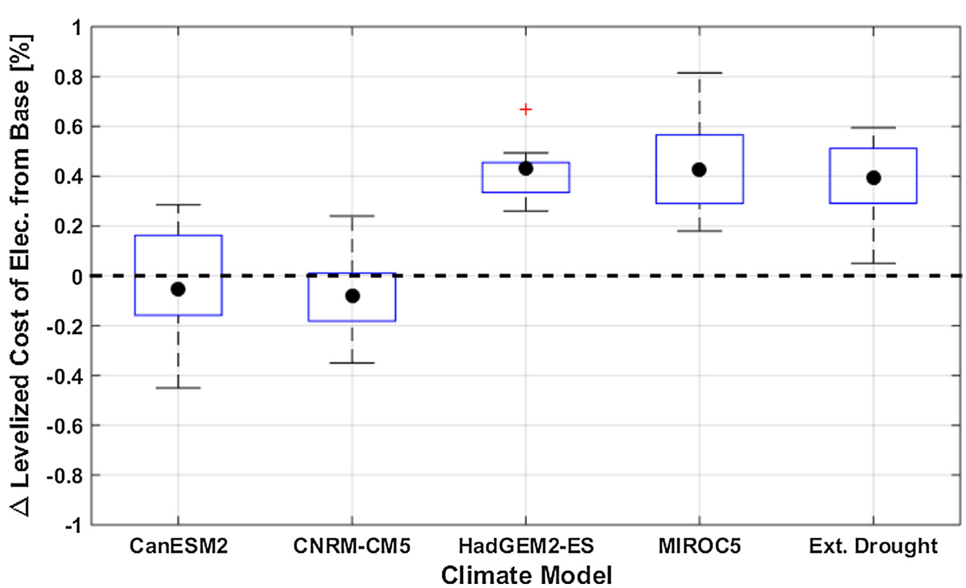

Fig. 7. Change in levelized cost of electricity (LCOE) from the base case under different climate models.

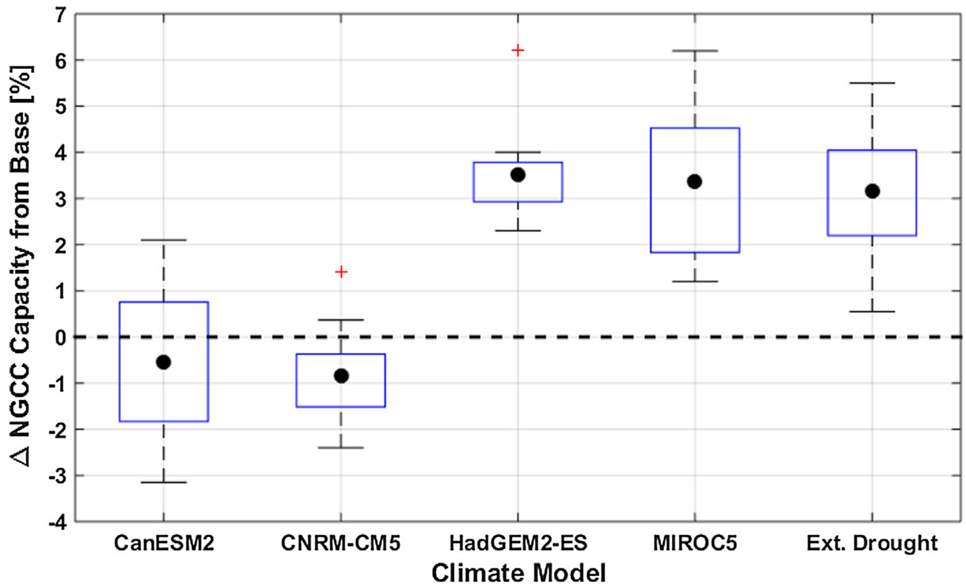

Fig. 8. Change in NGCC capacity requirements from the base case under different climate models.

when the emissions cleanup equipment is not operating in its most effective range, which contributes to increased criteria pollutant emissions. Additionally, this introduces more thermal fatigue that results in increased maintenance costs.

The CanESM2 and CNRM-CM5 models exhibited decreases in total NGCC start-up events across all power plant downtime periods. The increased hydropower generation in these models generally displaces the use of NGCC power plants. While these models did exhibit increased variability in reservoir inlet streamflow, much of that variability is buffered from impacting the electric grid since during events when water is spilled in a particular reservoir, hydropower generation from that reservoir remains unchanged. The drier models exhibited increases in the total NGCC start-up events primarily since these cases required more NGCC power plants to be installed in the system to meet peak demands and compensate for the shortfall in hydropower generation. For all of the cases, the largest changes occurred in the 4–20 h downtime range with the CanESM2, CNRM-CM5, HadGEM2-ES, MIROC5, and Extended Drought cases having exhibited −1.8%, −1.4%, +2.2%, +1.5%, and +3.4% in total NGCC start-up events respectively. This occurred due to the strong diurnal variability in solar and wind generation.

The results for the annual average start-up events per power plant unit are presented in Fig. 10:

In general, the amount of start-up events per power plant unit decreased across all downtime categories. The exceptions were the CanESM2 model which showed slight increases in the less than 4 h and 20–40 h, and 40+ hour downtime categories, and the CNRM-CM5 model which showed a slight increase in the 40 + hour downtime category. The HadGEM2-ES model exhibited the largest decrease in the less than 4 h downtime category of −3.1%, while the MIROC5 model exhibited the largest decreases in the 4–20 h, 20–40 h, and 40+ hour downtime category of −1.3%, −2.4%, and −2.8%, respectively.

From the results in Fig. 8, climate change impacts on hydropower increased the required NGCC capacity to ensure peak loads are met. While these peaks in the remaining load profile were large in magnitude and necessitated the increase in installed capacity, these peak load events did not occur very often. Therefore, a large portion of the NGCC capacity which is used only to meet these events remained offline for

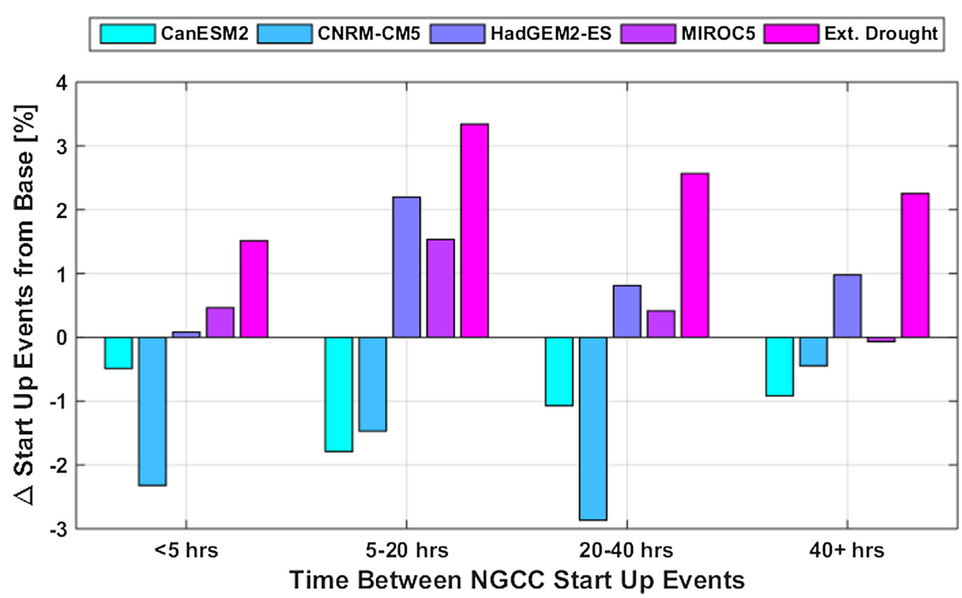

Fig. 9. Change in total NGCC start-up events by type from the base case under different climate models.

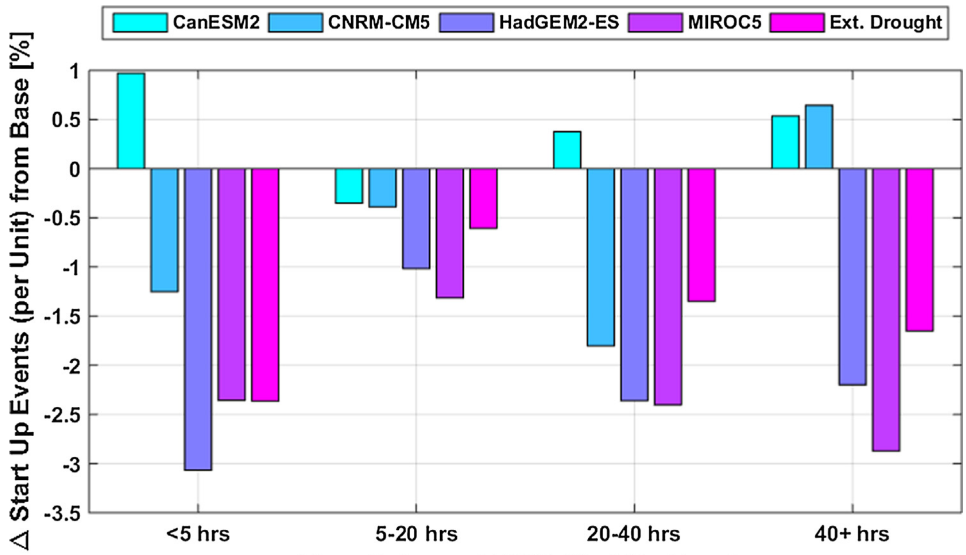

Fig. 10. Change in annual average NGCC start-up events per power plant unit by type from the base case under different climate models.

the majority of their lifetime. This is shown more explicitly in Fig. 11, which shows a histogram of the number of occurrences (hours) when different fractions of the NGCC power plant fleet were offline.

It was shown that the distribution shifts towards having higher fractions of the NGCC power plant offline. The result was a decrease in the average number of start-up events per NGCC power plant unit installed in the system. The variability in hydropower generation was strongest for the HadGEM2-ES and MIROC5 models, which consequently exhibited the largest decrease in start-up events per power plant unit. The CNRM-CM5 model also had increased variability in hydropower reservoir inflows, but the increase in overall water volume buffered the translation of this variability to electricity generation. The Extended Drought case had a lower overall water volume but is more consistently dry from year to year, and therefore had a smaller decrease in start-up events per power plant compared to the other dry models (HadGEM2-ES and MIROC5).

Overall, climate change impacts on hydropower in a highly renewable electric grid increased the required capacity of dispatchable power plant capacity (NGCC power plants in this case), increased total start-up events indicating higher criteria pollutant emissions from the electric grid, but decreased the start-up events per power plant unit and therefore prolongs power plant unit lifetime. These results, while small in magnitude, need to be taken into account to ensure that the electric grid can support high wind and solar capacities under future climate change conditions.

5. Conclusions and discussion

In this study, the effects of hydropower generation under climate change on the performance and operation of a future, highly renewable electric grid configuration were examined in the year 2050. The main findings of the study are as follows:

- **Electric grid greenhouse gas emissions may increase due to the higher variability of hydropower generation under climate change.** Even when the available water volume is larger than the

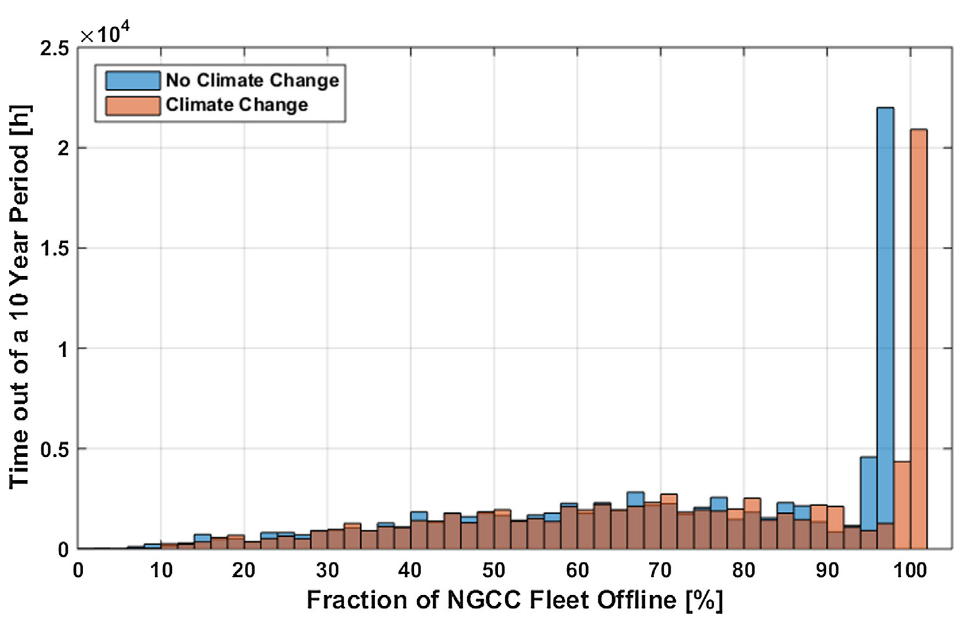

Fig. 11. Histogram of the amount of hours when different fractions of the NGCC power plant fleet are offline.

historical climate case, increased spillage reduces the amount of water that passes through the turbines at hydropower facilities. This results in lower hydropower generation which is compensated for by carbon-emitting power plants. This effect is mitigated only when the available water volume is significantly larger from the historical climate case.

- **Hydropower under climate change has minimal effects on electric grid renewable penetration and the system-wide levelized cost of electricity.** We observed changes of less than 1% from the historical climate case for each of these metrics for all scenarios considered in this study.
  - o The effect of system-wide cost increases on individual stakeholders, however, will vary. Individual stakeholders such as natural gas combined-cycle power plant owners may still be subject to cost increases.
- **Dispatchable power plant capacity will need to be increased to support to a highly renewable electric grid under conditions where hydropower is affected by projected climate change.** Higher variability in hydropower generation increases the peak of the remaining load profile that dispatchable power plants are tasked with meeting.
- **Hydropower under climate change will increase total natural gas power plant start-up events and associated criteria pollutant emissions.** To compensate for shortfalls in hydropower generation as predicted by certain climate models, more power plants needed to be activated to provide bulk electricity generation to balance generation and load. These additional start-up events can cause power plants to produce higher criteria pollutant emissions.
- **Hydropower generation under climate change will decrease the average number of start-up events per individual natural gas power plant.** While total start-up events increases to provide bulk generation, the maximum power plant capacity also increases. Therefore, the average power plant installed in the system will spend more of its lifetime offline since many will only be needed to start-up during these peak load events.

These findings have various implications for the planning of electric grid resources to support a future electric grid that integrates high levels of wind and solar power. Additionally, different stakeholders (utilities, power plant owners, independent system operators) in the future electric grid will be affected to different extents. There are various methods by which the planning of the electric grid itself or the complementary water management infrastructure can be altered to become resilient against impacts presented here.

In all the climate models examined, the total water volume introduces into the reservoirs is higher than that in the historical (2000–2009) period, but three of the models still exhibit decreased hydropower generation due to spillage. Innovative strategies regarding the management of surface water reservoirs can potentially reduce spillage volume and reduce or mitigate the greenhouse gas impact of climate change effects on hydropower generation. The management of the water infrastructure, however, is much more decentralized than the electricity infrastructure in California and therefore will face unique challenges in achieving this objective. Specifically, the management of the electricity infrastructure is the responsibility of the California Independent System Operator at the transmission level and utilities at the demand and distribution level, where the three investor-owned utilities (Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric) serve the vast majority of consumers. The water infrastructure, on the other hand, is managed by a large number of regional or municipal utilities, each with their individual procurement plans. Therefore, the jurisdictions of water and energy utilities rarely align, and many different water utilities with potentially different interests may exist within the territory of one electric utility. This can pose challenges for decision making, since many different water entities will need to cooperate to coordinate decisions that spread over the territory of one electric utility.

Increasing the use of low- or zero- carbon fuels in dispatchable power plants such as biogas or hydrogen produced from wastewater treatment plants or landfills can also reduce greenhouse gases. Increasing the scale of wind and solar installed on the electric grid with appropriate load shifting technologies can also be used to mitigate greenhouse gases. However, it should be noted that the electric grid configuration utilized here already incorporates a large capacity of wind and solar resources.

While the results show that the system-wide cost of electricity is minimally affected by hydropower generation under climate change, the costs endured by the owners and operators of dispatchable power plants will increase. The reduction in average start-up events per power plant can prolong the lifetime of the power plant and reduce degradation rates. However, since most of these power plants will only be activated to meet infrequent peak load events, the investment cost in these power plants may not be recovered by revenue through generation or the electricity sold by these power plants will need to be priced at very high levels. Mechanisms for more accurate valuation of the services provided by dispatchable power plants may be needed for these units to remain in operation to support load balancing in a highly renewable electric grid under climate change. Costs for owners of these power plants may need to be reduced with incentives for using renewable or low-carbon fuel.

The increase in total power plant start-up events indicates increased criteria pollutant emissions, which can be problematic for units located within degraded air basins. In California, power plants located with the South Coast Air Basin have limits on the number of start-up events due to air pollutant emission concerns. In a highly renewable grid under climate change, technological strategies for reducing or eliminating air pollutant emissions during start-up (i.e. cleanup equipment, switching to fuel cells instead of NGCCs, etc.) may need to be implemented to allow these power plants to operate flexibly enough to support the electric grid.

Each of these aspects can be explored in future research studies. For example, conducting a study to quantify the benefit of novel water management strategies that reduce spilled volume and increase hydropower utilization to offset more natural gas generation can provide interesting insights into how sustainable water management can have a key role in supporting renewable energy utilization goals. More in-depth studies should also be conducted on the cost implications of climate change impacts on hydropower by studying how these costs are distributed to different stakeholders such as utilities, power plant owners, hydropower operators, and ultimately to consumers. These studies could provide insight into changes in market structure or needs for policy mechanisms to mitigate impacts to disproportionately burdened entities. Further research can also be focused on determining how the future electric grid resource mix can be altered to better resist any undesirable impacts associated with climate change on hydropower.

Finally, the results presented in this study can be applied in the following ways. These results can be used by planning agencies, utilities, and policymakers for developing resource procurement strategies that avoid some of the undesirable effects presented here. This can allow for the development of more robust resource mixes that achieve long term policy goals while increasing the resilience against the impacts of climate change. For example, the results can be used to determine the amount of alternative flexible resources that can be installed such as additional energy storage capacity that can mitigate the need for increased NGCC capacity. Further, the results regarding impacts on GHG emissions and renewable penetration can be used to plan for the long-term procurement of resources to meet California's GHG reduction and RPS goals to proactively account for additional emissions from climate change impacts and mitigate them.

Acknowledgments

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Appendix A. Applying study methods to other regions

This section provides a short summary of the model types and data types needed to replicate the study performed here for regions outside of California. This summary is organized into subsections explaining the different types of models needed to perform this analysis and the data types required to utilize these models.

A.1. Water reservoir modeling

The first key component is to have a platform that can model the release of water from each reservoir under consideration in the region of interest as a function of reservoir fill, inflow, water demand, and constraints on maximum and minimum flows. Such a model can be constructed in different ways, ranging from a rule-based model that is calibrated to historical data to an operations optimization-based model that seeks to maximize certain objectives. This model will be used to capture the response of water releases from each reservoir to changes in inflow due to climate change.

For each reservoir considered, the following data will be needed to model the response of the reservoir system to changes in inflow due to climate change:

- Historical Reservoir Fill Profile:
  - o This refers to temporally-resolved data on the amount of water stored as a function of time over a historical time period. This data is used for calibration of reservoir model parameters.
- Historical Reservoir Release Profile:
  - o This refers to temporally-resolved data on the amount of water released as a function of time over a historical time period. This data is used for calibration of the reservoir model parameters.
- Historical Reservoir Water Demand Profile:
  - o This refers to temporally-resolved water demands imposed on reservoirs for water releases based on local needs such as environmental flows or water supply. This data is used for setting constraints on the water releases determined by the reservoir models.
- Reservoir Capacity Parameters:
  - o This refers to parameters such as water capacity, maximum and minimum fill levels, and hydropower head. These are typically used as constraint inputs in reservoir operational models.
- Historical and Future Inflow Profiles:
  - o This refers to temporally resolved data on streamflow or runoff that governs inflow into each reservoir under consideration. This data can be obtained from records for historical data, and future data can be composed from applying differences between time periods in climate models to the historical dataset.

With these data types acquired for each reservoir under consideration, the response of water reservoir releases to changes in inflow due to climate change can be determined.

A.2. Hydropower generation modeling

The second key component is to have a platform that can model how each hydropower facility provides electricity services (generation, spinning reserve, etc…) on an hourly basis in a given region, within the water release amounts determined by the water reservoir modeling. In this case, the daily (or longer) resolved water release amounts determined by the reservoir modeling are set as constraints on the dispatch of hydropower generation – the amount of water released to generate hydropower for any type of electricity service must be equal to that determined by the reservoir model unless there is a spillage event.

In this study, the hydropower generation modeling took the form of an optimization model which determines, on an hourly basis, how much of the capacity of the hydropower facility is committed to providing different types of electricity services. To operate such a model, the following data types are required:

- Hydropower Facility Parameters:
  - o This refers to parameters of the hydropower facilities attached to the reservoirs such as maximum power capacity, number of turbines, efficiency, and head.
- Price Profile of Electricity Generation:
  - o This refers to the hourly-resolved price of electricity at which the hydropower facility can sell produced electricity for bulk generation. This dataset can be obtained from different sources and constructed in different ways. For example, a time-of-use structure or data from electricity market operations can be used. Alternatively, this can be provided from the output of an electric grid model which determines the price of electricity before implementing hydropower generation, as is the case in the current study.
- Price Profile of Ancillary Services:
  - o Similar to the price profile for electricity generation, this also refers to hourly-resolved prices at which hydropower facilities can sell other electricity services such as spinning reserve and frequency regulation. These can be obtained from a similar set of sources as that for the price profiles of electricity generation or artificially constructed depending on the study scope.

With these price inputs, the hourly-resolved hydropower generation profile from all facilities in the region of interest can be determined. These profiles can then be used to perturb the operations of the electricity system to which the hydropower facilities are connected to.

A.3. Electric grid modeling

The third key component for replicating this study is a platform which can simulate the operation of electric grid resources to changes in the hydropower generation profile. Electric grid modeling platforms are very diverse and their composition depends on what characteristics need to be captured. On the one hand, such models can range from simple models which determine changes to the net load demand profile and use this profile to infer information about the operation of other resources such as NGCC power plants, to very complex models which model the individual characteristics of different power plants and captures dispatch in response to market conditions.

Regardless of complexity, electric grid modeling platforms must have the following data inputs:

- Temporally-resolved Electric Load Profile:
  - o This refers to the hourly-resolved demand for electricity in the region of interest.
- Capacity and Generation Profiles of Other Electricity Generation Resources:
  - o This refers to the amount of different electricity generation technologies by type and the hourly-resolved electricity generation

profile that these resources provide to meet the electric load profile.

- o The electricity generation profiles can either be assumed to be fixed (i.e. for wind and solar) or determined based on other factors such as electricity markets and needs for reliability services.

Generally, these models must operate under the constraint that electricity generation must satisfy the electric demand at every hour of the time period considered. With at least these data inputs for the region under consideration, the effect of changes in the hydropower generation profile on the ability of the electric grid to meet the electric load demand can be measured. The more aspects of the response of the electric grid that are of interest to capture, however, the more complex the modeling platform must be and more data types will need to be included.

Appendix B. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2018.12.079.

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